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Prediction of Oil Rim in Petroleum Reservoir Based on Compositional Gradients: A Real Case Study from Haripur Field.

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Abstract
The first oil producing field is Haripur Field, from the well no. SY-7 the reservoir produced approximately 0.53 MMSTB of oil with average flow rate 207 STB/D starting at 1987 and end at 1994 which make interest among the reservoir engineers for further investigation to delineate the oil bearing zone. Compositional gradient analysis is a proven and authentic technology to detect the gas-oil-contact (GOC) in the reservoir fluid column by collecting a reservoir fluid sample from a reference depth. In this study oil sample is collected at depth 2030 m and analyzed its Pressure Volume Temperature (PVT) properties with PVT cell to determine composition and API gravity. From this investigation outcome a compositional grading in the reservoir fluid column is modeled and detected the gas-oil-contact (GOC). The compositional grading model is validate by the seven years oil production rate and tube head pressure history matching through reservoir simulation study.

Keywords
Oil Rim, Compositional Grading, Gas-Oil-Contact, Pressure-Volume-Temperature, Reservoir Simulation, History Matching.

Introduction

In most petroleum reservoirs the gravity drives the heavier componentsof reservoir fluid toward deeper zones, on the other hand lighter components towards upper zones developing oil rim at lower zone and gas cap at upper zone coexisting at equilibrium in the reservoir. However, this is not always the case, because there are other reasons that may oppose this factor like a temperature gradient, capillary pressure, reservoir compartmentalization, reservoir filling, density overturn, and genesis processes. There are numerous reports of such phenomena in the literature.

The search for the optimal development of a field involves proper knowledge of the composition of the fluids that impregnated reservoirs and the development scheme could be strongly affected by the connectivity between the different reservoir units. After their migration into the trap, the fluids are shaped by various forces, among them; gravity has the most striking effect and was widely studied. In many cases there is evidence for the contribution of other forces like thermal gradients. Taking into account all the phenomena in order to establish a consistent picture of fluids distribution in the field is an important challenge for the petroleum industry. Reciprocally the actual fluid distribution can be used to assess the connectivity of the different panels and layers. But in that case, all the possible compositional redistribution mechanisms have to be taken into account (Pedersen *et al*., 2003).

Drawing on field examples, a methodology will be proposed for dealing with any kind of reservoir fluid systems. Once the model matches the observed compositional gradient and corresponding PVT properties, it allows reliable connectivity assessment and extrapolation to the whole reservoir fluid column.

Inany comprehensive reservoir study, the first step, which is necessary to be done before estimating the fluid in place, initializing reservoir simulators, and planning the reservoir development, is accurate assessment of the spatial distribution of the fluid components in horizontal and vertical directions. The fluid composition varies with depth in many reservoirs, and this phenomenon is referred to as “compositional grading” which, in most cases, is observed as an increase in the oil density with depth. This phenomenon can significantly affect different aspects of reservoir development.

In this work, we develop the model to simulate variation in composition of a nonisothermal two-phase petroleum fluid column using an equation of state (EOS). We consider effects of gravity and temperature gradient with the assumption of stationary fluid (no net mass flux, steady state) and propose a new algorithm which is convenient to be used in the commercial reservoir simulators, and the algorithm can also predict the location of GOC in a two-phase hydrocarbon reservoir system. The model may not work for the cases where there is natural convection or fluid flow caused by production in the reservoir.

Development of Compositional Gradient Model

In a nonisothermal reservoir there always heat diffusion occurs from warmer to colder regions, this irreversible phenomenon induces a molecular diffusion in the reservoir (Soret effect) as Onsager'stheory states (Onsager, 1931a, b; Kempers *et al.,* 1989). In a petroleum reservoir with no horizontal temperature gradients (the concept can be applied for the case when there is a horizontal temperature gradients as (Faissat *et al.,* 1994) the entropy generation per unit time and volume can be written as (De Groot, 1951):

$$\sigma = -\frac{1}{T^2}\vec{J}_q\frac{dT}{dh} - \frac{1}{T}\sum_{i=1}^{n_c} J_i\left[\frac{T}{M_i}\frac{d(\mu_i/T)}{dh} - \vec{g}\right] \ldots\ldots(1)$$

Where is heat flux, molar diffusion of component i relative to the center of mass velocity.

The final working equation in nonisothermal Compositional Gradient (CG):

$$d_T \ln(f_i) = \frac{M_i\vec{g}}{RT} - Q_i^{net}\frac{dT}{RT^2} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(2)$$

Where fi denotes the fugacity of component i in the mixture which can be easily calculated fromEOS.

Representative Samples

The concept of a "representative" sample has traditionallymeant a sample that represents the "original" reservoir fluid. This definition may be misleading for the following reasons:

1. Even if a sample is obtained, representative of an originalinsitu fluid, this sample may only be representative of aspecific depth or depth interval of the reservoir. A uniformfluid composition does not always exist throughout areservoir because of compositional variations; verticalvariations due to gravity and thermal effects, and othervariations between fault blocks and non-communicatinglayers.

2. It may be impossible to obtain a truly representativesample of insitu fluids because of near-wellboremultiphase behavior in saturated, slightly undersaturated,and low-permeability reservoirs.

3.Samples which are not representative of insitu fluids can be used to "create" near-exact representations of originalinsitu fluids.

4. Accurate PVT data and compositions of samples that arenot representative of insitu fluids are still useful indeveloping an EOS fluid characterization (as useful assamples that are representative of insitu fluids). Based on these observations, we introduce a more generaldefinition of a representative sample: a "reservoir representative"sample is any sample produced from areservoir. As a special case, an "insitu-representative" samplerepresents the volume-weighted average of original fluid(s) in the depth interval drained by a well during sampling. Reservoir-representative samples are readily obtained, and in many cases they can be used to create accurate estimates ofinsitu-representative fluids. Direct sampling of insitu representative fluids, on the other hand, may be difficult orimpossible.

Two important points should be made about theapplication of representative samples:

1. Accurate insitu-representative samples are used to determine the initial hydrocarbons (oil and gas) in place. Insitu-representative samples may vary as a function of depth, from one fault block to another, and between noncommunicating layers. All insitu-representative samples are needed in the difficult task of defining hydrocarbons in place.

2. All reservoir-representative samples having reliable PVT data and accurately-determined compositions should be used simultaneously in developing an EOS fluid characterization. The resulting characterization, with a single set of EOS parameters, can be used to consistentlydescribe the phase and volumetric behavior of all fluid swithin the reservoir. Unfortunately, the "mapping" of original insitu compositions for a reservoir may not be possible until several wells have been drilled and production data become available.On the other hand, an EOS fluid characterization can be developed as soon as one reservoir-representative sample is available. This characterization can be used for preliminary calculations based on simplified assumptions about the original hydrocarbons in place.

As additional representative samples and PVT data becomeavailable, the EOS characterization can be modified asnecessary to match both the old and the new PVT data. Ifadditional insitu-representative samples become available, new estimates can also be made of the original hydrocarbons inplace.

Case Studies

In this study, we took reservoir fluid sample collected from bottom hole of the well no. SY-7, which is the first oil producing well in Bangladesh, at depth 2030 meter of Haripur field. The bottom hole sample is analyzed by PVT cell in fluid analysis laboratory for estimating API gravity, composition and C_{7+} characteristics. Laboratory analysis yields results presented in table 1.

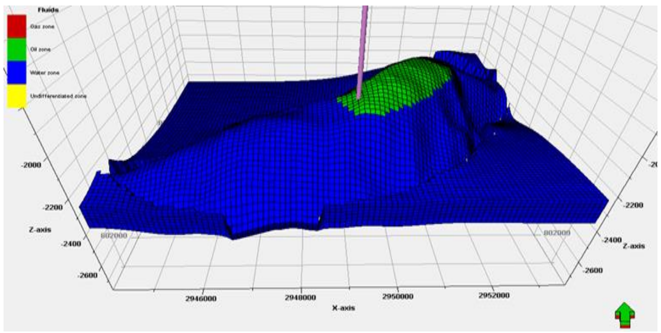

Figure 1: Location of well no SY-7 in reservoir

The well completion is presented in fig. 2. Three size of casing is used and 5 inch diameter of production tubing completion. Packer is set between casing and tubing and the well is perforated along the oil zone.

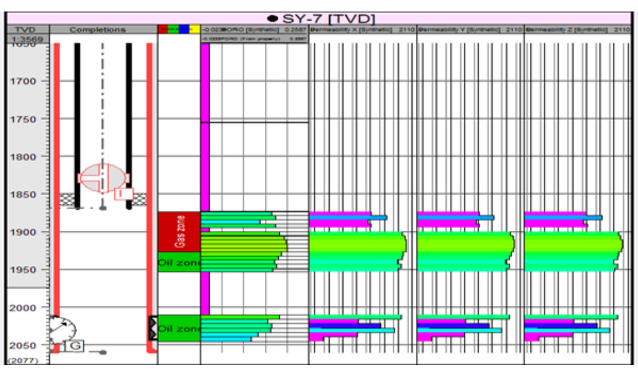

Figure 2: Completion of well SY-7 and Sampling location

The fluid analysis yield composition of oil sample shown in the table 1 below where 11 component composition model is developed consisting methane is 41.52% and C7+is 46.5% and characterizedshown in table 2.

Table 1 Mole Percentage of Oil Sample and C_{7+} Characteristics

Component Name	Mole Percentage Mol%	Molecular Weight, M_w	Specific Gravity SG
CO2	0.28	44.01	
N2	0.30	28.013	
C1	41.52	16.043	
C2	5.10	30.07	
C3	1.89	44.097	
IC4	0.80	58.124	
NC4	0.95	58.124	
IC5	0.53	72.151	
NC5	0.48	72.151	
C6	1.65	84	
C7+	46.50	220.857	0.85336
Total	100.0000		

Pure components properties of the oil sample are taken from Lee-Kasler properties library such as molecular weight, critical pressure, critical temperature and acentric factor. These thermodynamic properties are used in the equation of state and fugacity calculation.

Table 2 Properties of Pure Components

Component Name	Molecular Weight	Critical Pressure P_c Bar	Critical Temperature T_c K	Acentric Factor ω_i
CO2	44.01	73.866	304.7	0.225
N2	28.013	33.944	126.2	0.04
C1	16.043	46.042	190.6	0.013
C2	30.07	48.839	305.43	0.0986
C3	44.097	42.455	369.8	0.1524
IC4	58.124	36.477	408.1	0.1848
NC4	58.124	37.966	425.2	0.201
IC5	72.151	33.893	460.4	0.227
NC5	72.151	33.701	469.6	0.251
C6	84	30.104	507.5	0.299
C7+	220.86	16.865	748.5	0.71302

Phase plot is drawn of the oil sample shown in fig. 3. The top (green) line is the bubble point line and the bottom (red) line is the dew point line. Between the bubble and dew point there lines five quality lines. The critical point of the oil sample is 712 K and 80 bar.

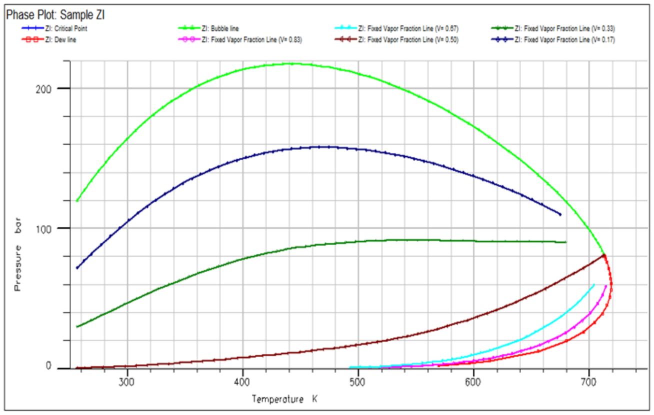

Figure 3: Phase diagram of the oil sample

At the reference depth 2030 m the oil pressure is 221.5 bar and the temperature is 377 K where the oil sample is collected. Starting from this reference depth compositional gradient is simulated up to 1750 meter.

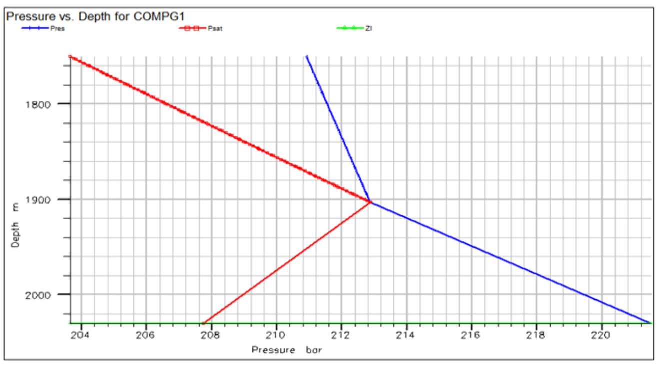

Figure 4: Saturation Pressure and Reservoir Pressure along with the depth

The variation of saturation pressure (Psat) and reservoir pressure (Pres) with depth is shown in fig. 4. At the depth 1901 meter the reservoir pressure is the same with the saturation pressure where the gas and oil are in mutually coexist in equilibrium shown in fig. 4.

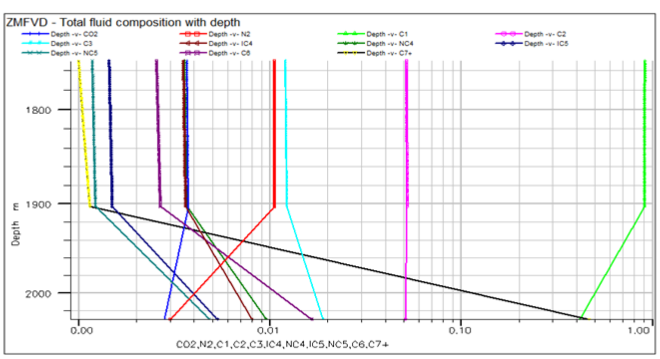

Fig. 5 Variation of component composition along with the depth

Component of Oil such as C_1 composition changes sharply from 41.5% to 90% at the depth of 1901 meter and C_{7+} composition changes sharply from 46.5% to 0.001 % at the depth of 1901 meter. Here the lighter component becomes rich at gas phase on the other hand heavier component becomes lean in gas phase. It can be predicted that gas oil contact exist at the depth 1901 meter shown in fig. 5.

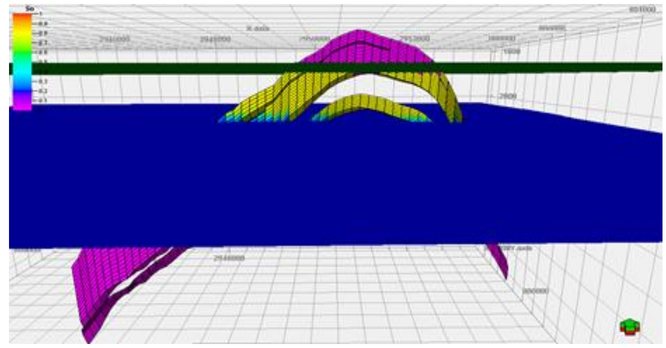

Figure 6: Position of the Gas-Oil-Contact (GOC) and Water-Oil-Contact (WOC)

From the above composition variation study the Gas-Oil-Contact (GOC) is predicted at 1901 meter and from the well log Water-Oil-Contact (WOC) at the 2030 meter. The oil zone is extended from 2030 meter to 1901 meter making 129 meter thick oil zone.

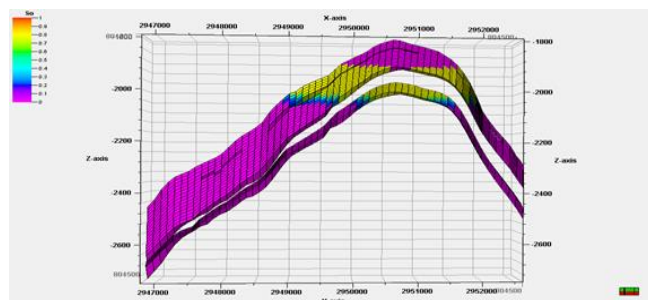

Figure 7: Position of the oil rim in 2D view

The oil zone is divided into two segments in Bhuban formation and lower Bokabil formation. In lower Bokabil formation there is a gas zone above the oil zone. The geological structure making the oil zone into an oil rim shape shown in figure 7 & 8.

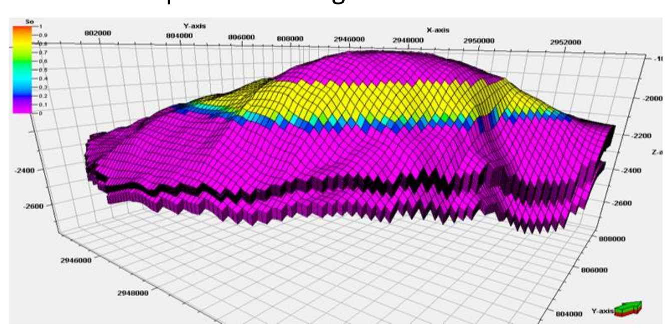

Figure 8: Position of the oil rim in 3D view

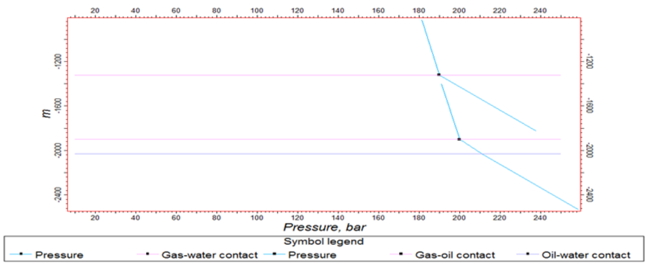

Figure 9: Pressure profile along with depth

In the oil zone the slope of the pressure profile is more than the slope of the pressure profile in the gas zone shown in fig. 9.

Validation of the Model

In Oil and Gas industry any prediction must be validate by the real performance of the reservoir. In this study black oil and streamline reservoir simulation models are developed with the predicted fluid contacts shown in fig. 10 and the oil producing and sampling well is placed in the simulation model. The dynamic reservoir simulation model generates oil flow rate and tube head pressure responses synchronized with the real reservoir responses from 1988 to 1994.

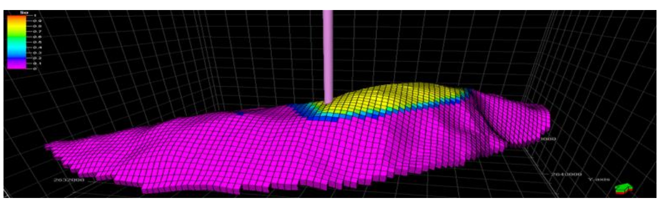

Figure 10: Reservoir simulation model and position of oil zone

The simulated pressure and oil flow rate performance from 1988 to 1994 is similar to the actual reservoir performance shown in fig. 11 and 12. The real responses are shown by dot points and simulation is represented by the solid line. Simulation trend makes average trend of the actual pressure.

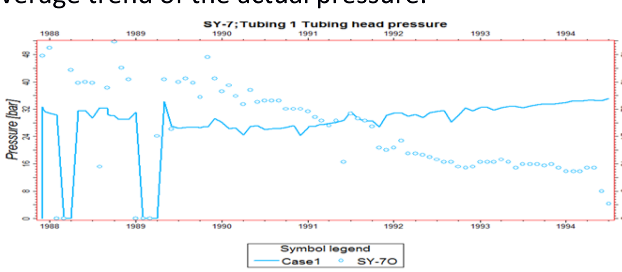

Figure 11: Observed and Simulated Tube Head Pressure

The simulated oil flow rate is presented by the solid line and the actual by the dot points. Simulated oil flow rate perfectly matches with the real flow rate shown in fig. 12 indicating that reservoir simulation model is the mirror image of the actual reservoir.

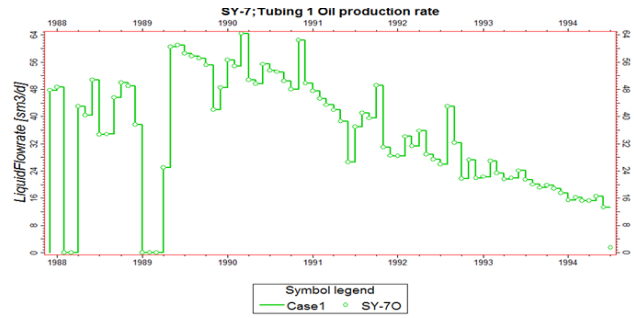

Figure 12: Observed and Simulated Oil Flow Rate

History Matching

When the geological model is complete, we should verify that it reproduces the observed rates and pressures during a simulation run. This is commonly used to prove that the model makes a reasonable prediction for the future. Usually users run tens or maybe hundreds of different simulations, in order to find the best match. The History Match Analysis allows us to easily and quickly analyze hundreds of simulation runs to find the best match. It is recommended to start off at a high level and then examine in more detail all the way down to obtain a data curve for every well.

The History match analysis tool calculates the absolute difference between the observed and the simulated values at each time step and then divides by the number of points used, to give users an averaged difference value or what we call the match value (M). It also normalizes the value by dividing the difference by a normalization parameter σ:

$$M = \sqrt{\frac{1}{N}\sum_{i=1}^{i=N}\left(\frac{S_i - O_i}{\sigma}\right)^2} \text{ ....}(3)$$

Here M is the match value, N is the number of time samples, Si is the simulated values and O_i is the observed values at time i.

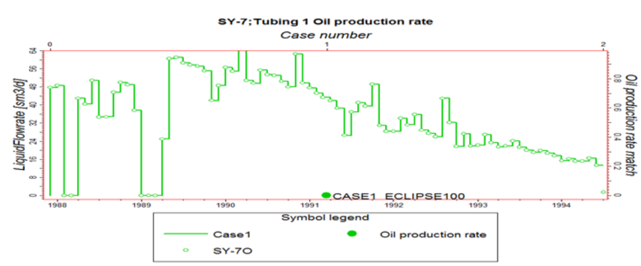

Figure 13: Oil Production Rate History Matching

The match value of oil production is 0.0 shown in fig. 13 which indicated that the observed and simulated oil production rate value is the same.

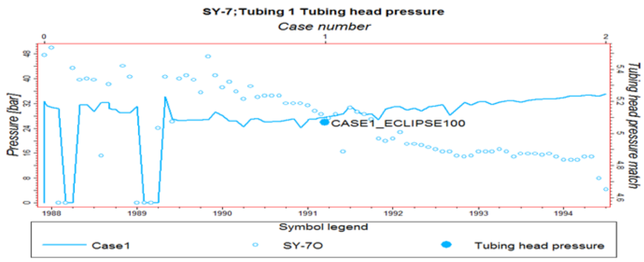

Figure 14: Tubing Head Pressure History Matching

The match value of tube head pressure is 5.1 shown in fig. 14 which indicated that the observed and simulated tube head pressure deviates from each other a little bit.

Results

Starting from the oil sample collected at depth 2030 meter, oil composition is estimated yielding C_1 is 41.52% and C_{7+} is 46.50%. By this reference composition at reference depth a compositional gradient model is simulated up to depth 1750 m yielding that gas-oil-contact exists at depth 1901 meter constructing an oil rim in the reservoir. The predicted fluid contact is inserted into a reservoir simulation model for validation of the prediction. The reservoir simulation model generates dynamic responses such as oil flow rate and tube head pressure matching with the observed data over seven years. The match value for oil production rate is 0.0 and tube head pressure is 5.1 indicating the best match.

Conclusion

In the petroleum reservoir hydrocarbon such as C_1,C_2 ...C_{100} etc. and non-hydrocarbon is making oil zone and gas zone under the influence of the gravity, capillary, thermal, chemical and mechanical forces in the reservoir. Generally oil zone is rich with heavier hydrocarbon and gas zone is rich with lighter hydrocarbon. There exists a gas oil contact between these two phases which is the prime objective of the engineers' to predict this gas-oil contact which is the main information for estimation the reserve and determining recovery techniques. In this study oil rim is predicted in the Haripur oil field by simulation compositional gradient in the formation and the prediction is validate with the seven years of observed data making this outcome authentic and validate for further field development study.

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